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COMMENTS OF THE AMERICAN PETROLEUM INSTITUTE ON THE ENVIRONMENTAL PROTECTION AGENCY'S DRAFT UNDERGROUND INJECTION CONTROL PROGRAM GUIDANCE ON TRANSITIONING CLASS II WELLS TO CLASS VI WELLS

February 28, 2014

The American Petroleum Institute (API) represents over 500 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.2 million U.S. jobs and 7.7 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. API has a strong interest in the development of the Underground Injection Control (UIC) program for Geologic Sequestration (GS) wells and provided extensive, detailed comments on the topics covered in this draft guidance documents as part of its comments on the proposed Class VI rulemaking.

API appreciates the opportunity to provide comment on this proposed guidance and wishes to express its support for the comments being submitted by the North American Carbon Capture and Storage Association (NACCSA). API's overall concern is that the guidance could be construed to add additional requirements to the regulations. Guidance may supplement, or flesh out, but cannot supplant, or contradict, the regulations. It is particularly important the illustrations and the wording in the guidance are not interpreted as new regulatory requirements in cases where the regulation is not prescriptive.

API is concerned that while the Environmental Protection Agency (EPA) claims it wants enhanced oil and gas recovery (ER) operators, who currently purchase and use natural carbon dioxide (CO2) from underground reservoirs, to also use captured "CO2 streams" from industrial emissions, either as additional CO2 sources or as substitutes for them (see 79 FR 1430, 1484 in NSPS Preamble), three of its recently issued CO2 regulatory documents create potential serious disincentives for oil and gas operators conducting ER to participate in EPA's carbon capture and sequestration (CCS) efforts.

Specifically, the three recent EPA actions that create potential disincentives to CO2 ER in general and use of anthropogenic CO2 in particular, are (1) the proposed New Source Performance Standards (NSPS) rule with a Subpart RR requirement (79 FR 1430, January 8, 2014), (2) the final Resource Conservation and Recovery Act (RCRA) rule on hazardous waste exemption (79 FR 350, January 3, 2014), and (3) the draft guidance on transitioning CO2 injection wells from UIC Class II to Class VI (EPA 816-P-13-004, dated December 2013, published on EPA's website). Taken together, these actions indicate EPA's intent to impose stringent Class VI requirements on all oil and gas operators who inject CO2, regardless of the CO2 source or the operators' primary purpose (ER or GS).

Even though EPA discussed an informal, non-binding 'safe harbor' in the UIC Class VI rule preamble, stating that "traditional ER projects" would not be impacted (75 FR 77230, 77245 (December 10, 2010)), EPA, in these three documents, construe this 'safe harbor' extremely narrowly. It would apply only to ER operations using natural CO2, not captured (anthropogenic) CO2 streams, and the 'safe harbor' may be eliminated entirely because EPA has set the stage in its guidance document to second-guess the ER operators' intent and purpose in operating their injection wells, potentially forcing them to change their existing permits to ones with significantly different terms, even if they neither change their primary business purpose from ER to GS nor use captured CO2 streams.

The comments that follow address the disincentives contained in the draft guidance on transitioning CO2 injection wells from UIC Class II to Class VI (EPA 816-P-13-004, dated December 2013, published on EPA's website) but should be viewed in the broader context of the regulatory environment created by all three documents.

Together, these impacts would undermine EPA's climate change policy that depends heavily on oil and gas companies' willingness to accept captured CO2 streams for their current ER operations (see 79 FR 1430, 1484 in NSPS Preamble). EPA should revise the draft guidance to uphold the premise in the final rule preamble that "Traditional ER projects are not affected by the Class VI rulemaking and will continue to be permitted under Class II requirements."

If API can be of further assistance, please contact Steven Crookshank of API's Policy Analysis Department (crookshanks@api.org or 202.682.8542).

Sincerely,

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The guidance conflates the two elements of EPA's Transition Rule, 40 CFR 144.19.

EPA does not clarify that there are two distinct requirements for obtaining a Class VI permit: first, the well operator must have "the primary purpose of long-term storage into an oil and gas reservoir" (40 CFR 144.19(a)) and second, there must be "an increased risk to USDWs [underground sources of drinking water] compared to Class II operations" (40 CFR 144.19(b)). The first element is to be judged from perspective of the ER operator and is addressed when a well operator applies for a UIC permit and declares the well's primary purpose (see EPA Form 7520-6 (Rev. 12-11), Item X. Class and Type of Well, and Attachment U, Description of Business). The nine factors in subsection (b) only apply to the second element, not the first; EPA or the state agency does not determine the well operator's primary purpose.

The draft guidance suggests though that the 'primary purpose' test is met by factors such as injection rates (pp. ii EPA "believes that if the business model … changes from an [ER]-focused activity to one that maximizes carbon dioxide injection volumes … then the [injection] risk" is likely to increase). In fact, an ER operator may increase or decrease injection rates for legitimate ER business purposes that have nothing to do with GS. If the different injection rates increase risks to USDWs, enforcement actions under Class II may be appropriate, but not changes of permit class. Because all UIC permits, including Class II, are premised on protecting USDWs, EPA cannot claim that increased risks justify changing the permit class. That would imply that Class II permits don't have any provisions to protect USDWs. EPA's guidance should only be needed when an operator requests a Class II permit for GS activities because it believes there are no increased risks to USDWs, pursuant to 40 CFR 144.19(a). Only then, EPA or a state agency "shall determine" if there is an increased risk to USDWs that requires the applicant operator to obtain a Class VI permit.

Moreover, the Transition Rule does not give EPA the power to force a well operator to change an existing permit to one with significantly different terms; such power over existing ER operations was neither proposed nor discussed in the final rule's preamble. Rather, EPA said existing ER operations would not be affected (75 FR 77230, 77245 (December 10, 2010). For existing ER Class II permits, EPA or the state agency may only enforce the Class II provisions, including protection of USDWs, which is in all UIC permits. EPA may not unilaterally change Class II permits to Class VI on its own volition. EPA or a state agency only determine if there is an increased risk to USDWs under subsection (b) when an operator files a new or revised permit application under subsection (a). Therefore, the two subsections of 40 CFR 144.19 must be read together as requiring two distinct elements, as demonstrated in the matrix below:

***Underground Injection Control (UIC) Class of Permit appropriate for Purposes and Risks*. 40 CFR 144.19**		**Operator's Primary Purpose:** Oil and Gas Production through Enhanced Oil and Gas Recovery (ER)	**Operator's Primary Purpose:** Long-term Storage into Oil and Gas Reservoir; Carbon Dioxide Geologic Sequestration (GS) 40 CFR 144.19(a)
No Increased Risks to Underground Sources of Drinking Water (USDWs), using factors in 40 CFR 144.19(b)		Class II Permit "Business as Usual" Operations; This serves as Baseline for evaluating increased risks after change of primary purpose from ER to GS.	Class II Permit, or Operator may choose to voluntarily convert to Class VI permit, which is optional and may be prompted by future carbon credit regime.
Increased Risks to USDWs, using factors in 40 CFR 144.19(b)		Class II Permit, with enforcement action available if increased risks to USDWs violate permit.	Class VI Permit required.

The guidance asserts the authority to require Class II owners/operators to conduct additional monitoring outside of Subpart RR.

EPA asserts that data related to increased risk may be offered up voluntarily by an ER owner/operator, or requested by a Class II or VI UIC Program Director. The Class II UIC Program Director is likely to be a state official (if Class II is delegated); the Class VI UIC Program Director would be federal EPA unless a state had sought and obtained primacy for Class VI. EPA claims this additional monitoring is based upon existing UIC authorities, but unrelated to MRV under a Subpart RR opt-in. API questions whether EPA's interpretation of 40 CFR 144.17 and other UIC provisions are as expansive as EPA cites, especially for existing ER permits. EPA is not empowered to embark on a general review of all Class II permits to unilaterally convert them to Class VI. In addition, the Class VI rule does not allow the UIC program Director to overfile on injection well classes that it does not directly regulate.

The guidance does not distinguish between natural and anthropogenic sources of CO_2.

The guidance document does not appear to limit itself to "CO_2 streams," defined as captured CO_2, but could encompass 'traditional projects' that use natural CO_2. Accordingly, under the guidance EPA would seem to be able to require conversion of Class II wells that inject natural CO_2. In particular, the guidance seems to suggest that EPA could conclude that an ER operator could be injecting natural CO_2 for the primary purpose of long-term storage and in that scenario – and if the increased risk test was also met – such a well might also be required to convert to Class VI. This conclusion is nonsensical as a commercial matter, but the guidance would seem to allow that outcome.

If this guidance is accepted as a correct reading of the CO_2 injection rule, it could:

Discourage oil and gas operators from using any CO_2, captured or natural, for ER.
Changing the primary purpose of a CO_2 injection well is a major business decision. It carries with it many long-term financial and regulatory obligations and would likely require an ER operator to obtain additional property or other legal rights, all of which will materially impact an ER-to-GS operator's business model. In addition, the operational requirements for a GS business model differ fundamentally from an ER business model, necessitating different training and skill sets that a company would need to establish before it could initiate any transition from Class II to Class VI. EPA dismisses these business and legal concerns by claiming that its well class determination has no bearing on any other legal issue (page 16, second paragraph). However, this is unrealistic, as an agency decision (i.e. mandating the conversion of a Class II well to Class VI) could be persuasive evidence in a legal proceeding alleging that an ER operator has exceeded its rights under its oil and gas lease, which usually grants rights only for oil and gas production, not long term storage, purposes. Furthermore, instead of buying a CO_2 stream for ER, a GS (former ER) operator could be selling pore space to the CO_2 capturer, because that could be its only way to recover Class VI obligation costs after oil and gas production ceases. This separate right to sell pore space is not in oil and gas leases and would likely need to be obtained by the ER operator before it changes its primary business purpose and applies for a UIC permit for this transitioned use under Class II, if no increased USDWs risk, or Class VI.

The Guidance does not apply to ER injections of water, natural gas, or other substances, therefore EPA should understand that operators might curtail their ER use of all CO_2, anthropogenic or natural, to avoid the potential that they would inadvertently subject themselves to the unilateral imposition of the additional requirements of a Class VI well permit.

Discourage new and expanded CO_2 flooding projects.
According to the guidance, the criteria for changing from Class II to Class VI injection wells include: 1) increased reservoir pressure, 2) increased injection of CO_2 into the reservoir, or 3) decreased production rate from the reservoir. A new CO_2 injection project or an expansion of CO_2 flooding in an existing project would require both 1) increasing reservoir pressure and 2) increasing CO_2 injection into the reservoir. Without addressing the first Transition Rule requirement of a changed primary purpose, any of these events could trigger a decision by the program director that these are now Class VI wells, even though the primary purpose remains ER. This unilateral change could effectively make any new CO_2 projects uneconomic as plume and pressure front monitoring will be required with monitoring wells and much stricter regulations on well construction and operations could be imposed before the operational capability could be adapted to meet them, and impose on the operator twenty years of long-term monitoring after closure.

Impact the cost of CO_2 flood project abandonment.
The abandonment requirements for Class VI injection wells are much more stringent and require twenty years of continuous monitoring after the well is abandoned. This would be very expensive for CO_2 projects with hundreds of injection wells. Therefore, at later stages of operations, the CO_2 flood operator would have a substantial incentive to plug all injection wells rather than to phase down operations (read: decrease production rate) which may trigger the re-classification of wells to the Class VI status.

Detailed Edits

The edits below flow from the comments above. Red text indicates additions; red strikethrough indicates deletions.

(Page ii-iii)
Owners or operators of Class II wells that are injecting carbon dioxide for the primary purpose of long-term storage into an oil or gas reservoir must apply for and obtain a Class VI permit where there is an increased risk to USDWs compared to traditional Class II operations using carbon dioxide [40 CFR 144.19(a)]. Two elements must exist: a change of the injection well's primary purpose from ER to GS and an increased risk to USDWs because of that change. If there is no intent to change the primary purpose, "[t]raditional ER projects are not impacted [...] and will continue operating under Class II permitting requirements." Any increased risks from ER operations are addressed under Class II permit enforcement proceedings. Conversely, if the "business model for ER changes to focus on maximizing CO2 injection volumes and permanent storage," but no increased risk compared to the existing ER operations, then Class II permittee may choose to continue under Class II or Class VI, which may depend on the relative value of future carbon credits. (Quoted provisions are in the GS Rule Preamble at 75 Fed.Reg. 77229, 77244-5). ~~EPA recognizes that there may be some carbon dioxide trapped in the subsurface at ER operations; however, if the Class VI UIC Program Director has determined that there is no increased risk to USDWs, then these operations would continue to be permitted under the Class II requirements~~. Only when the primary purpose, or business model, changes **and** the potential risk to USDWs increases must a former oil and gas owner or operator obtain a Class VI permit. EPA has identified factors for owners or operators and Class VI UIC Program Directors to consider when determining if risks to USDWs have increased [40 CFR 144.19(b)] after the primary purpose has changed. No single factor should be relied on to make a determination of ~~injection purpose and~~ potential risk to USDWs, as some factors may indicate risks to USDWs decrease due to the change. Rather, all available factors should be considered in determining the appropriate well class for a carbon dioxide injection well in an oil or gas reservoir after the owner or operator has decided to change the injection's primary purpose.

Once the primary purpose has changed from ER to GS and the evaluation of factors shows that potential risks to USDWs will increase, ~~a determination has been made that~~ a Class VI permit is needed to transition to GS operations and ~~continue injection,~~ a number of requirements must be fulfilled, both at the time of re-permitting and during future operations. The owner or operator must demonstrate that the proposed injection well is appropriately constructed and operable as a Class VI well and will not endanger USDWs [40 CFR 146.81(c)]. The Class VI Rule describes the requirements that must be met in order to grandfather existing Class II wells to Class VI wells, including a demonstration that the wells meet the requirements at 40 CFR 146.86(a). This guidance document describes a number of requirements an owner or operator must follow including well construction and operation, GS site testing and monitoring, post-injection site care (PISC) and emergency and remedial response, among other requirements. In addition, a Class VI well owner or operator must adhere to more comprehensive operating requirements than those required for Class II wells, as specified at 40 CFR 146.88. Mechanical integrity testing requirements for Class VI wells at 40 CFR 146.89 are more rigorous than those for Class II wells. Some testing and monitoring procedures are unique to Class VI wells, such as plume and pressure front tracking [40 CFR 146.90(g)]. PISC [40 CFR 146.93] and emergency and remedial response [40 CFR 146.94] requirements are also unique to Class VI wells. These combined requirements provide protection for USDWs and are tailored to the longer timeframes and greater injection volumes expected at GS operations.

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Class II wells means wells that inject brines and other fluids associated with oil and gas production, or storage of hydrocarbons and wells that inject carbon dioxide into oil and gas reservoirs for the primary purpose of long term storage (40 CFR 144.19(a)) and do not increase risks to USDWs (40 CFR 144.19(b)). Class II well types include salt water disposal wells, enhanced recovery wells, and hydrocarbon storage wells.

(Page x)
Injectivity is a measure of the ability of an injection well to receive fluids. ~~refers to the efficiency of displacement of an injected fluid into porous rock, both within the rock (micro-displacement efficiency) as well as from the perspective of total pore space (sweep efficiency).~~

(Page 1)
The Underground Injection Control (UIC) Program of the United States Environmental Protection Agency (EPA) is responsible for establishing regulations for the construction, operation, permitting and closure of injection wells through which fluids are placed underground. EPA's regulations, at Title 40 of the Code of Federal Regulations (CFR) Parts 144 through 148, establish six classes of injection wells, based on the type of injection activity and types of fluids injected. Class II injection wells (formally defined at 40 CFR 144.6) are wells into which fluids associated with oil and gas production are injected, including carbon dioxide injected for the purpose of enhanced recovery (ER). The EPA rule *Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* [40 CFR 146.81 et seq.], referred to in this document as the Class VI Rule, created a new UIC injection well category, Class VI, specifically for the injection of carbon dioxide for the purpose of geologic sequestration (GS). The Safe Drinking Water Act prohibits EPA from imposing on States any regulations that would "interfere with or impede" enhanced secondary or tertiary recovery from oil and gas fields, unless "essential" to protect USDWs. 42 U.S.C. 300h(b)(2)(B). This frees oil and gas operators from non-essential restrictions that may be imposed on other operators' activities.

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EPA recognizes that it is very likely that some carbon dioxide will be trapped in the subsurface as part of ER operations; however, if there is no increased risk to USDWs, then these operations would continue to be permitted under Class II requirements. Traditional EOR projects are not affected by the Class VI rulemaking and will continue to be permitted under Class II requirements. If the business model for ER changes to focus on maximizing CO2 injection volumes and permanent storage, then the risk of endangerment is USDWs is likely to increase, however this would not necessarily be the case if the injectate and the pressure limitations are the same, particularly in the early part of GS operations. Once this intentional change in the "primary purpose" of the injection has occurred, t~~T~~he Class VI Rule lists several factors that the UIC Program Director must consider to determine if risks to USDWs have increased and a Class VI permit is required [40 CFR 144.19(b)].

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Oil and gas operators enter into oil and gas leases and surface use agreements from numerous landowners to drill Class II wells and develop oil and gas fields. These rights are granted for the exclusive purpose, and contain conditions to enforce the purpose, of exploring for and producing oil and gas, which usually includes the right to conduct enhanced recovery operations. These property rights are well-developed judicially in the states listed above and may be terminated if the conditions are

violated, depending on each state's specific property law regime and the language in the lease. Generally, the rights granted under an oil and gas lease do not permit an oil and gas operator to use ER injection wells for a GS purpose. If an oil and gas operator makes the business decision to convert its operations from ER to GS, after evaluating numerous legal and economic issues, it will likely need to enter into new agreements with the landowners. One basic issue is the potential that the GS operations would put the oil and gas operator at risk of losing its property rights under an oil and gas lease.

(Page 16-17)
Owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI permit when there is an increased risk to USDWs compared to Class II operations [40 CFR 144.19(a)]. As noted above, the owner or operator decision to change the primary purpose from ER to GS is a critical first step before any determination can be made whether a Class VI permit is required due to increased risks to USDWs. While considering the numerous legal and economic factors in making this initial decision, oil and gas operators will continue to be regulated under Class II; any increased USDW risks from their operations would be addressed in Class II enforcement actions. If a Director believes an oil and gas operator is attempting to remain improperly under Class II coverage while engaging in long-term storage as its primary purpose, the Director may allege those claims in a Class II enforcement action and seek appropriate remedies, including permit revocation, with the concomitant protections of due process and judicial review. A second-guess determination that the primary purpose has changed from ER to GS could jeopardize significant contractual and property rights, therefore it must be made by the oil and gas operator or a court with due process protections, not a government official based on hypothetical models.

This guidance document discusses the "primary purpose" of the injection only as it relates to and supports an identification within EPA's UIC Program of the appropriate UIC well class under which a well injecting carbon dioxide must be permitted. The determination of primary purpose for the UIC well class evaluation may have little or no bearing on how the purpose of the well is defined for other regulatory programs or activities but will likely have major bearing on many legal and business issues.

The determination of the need for a Class VI permit is based on a well's primary purpose and then on risk to USDWs. In the Class VI Rule, EPA identified several factors that indicate a change in project operations that may increase risks to USDWs. After a change of primary purpose, t~~T~~hese factors are to be considered by owners or operators and Class VI UIC Program Directors when determining whether a Class VI permit is required for carbon dioxide injection in wells currently permitted as Class II wells. They may also be considered by owners or operators applying for a permit for a Class II well to inform business decisions prior to deciding whether to permit a well as a Class II or Class VI well. Considering these factors ahead of time may also ease the transition process at a later point in time. These factors are established in the Class VI Rule at 40 CFR 144.19(b), and include: (omitted)

EPA developed these factors to inform a determination regarding whether an increased risk to USDWs warrants re-permitting a project from Class II to Class VI. No single factor from this list should be independently relied upon to make determinations. Rather, all available factors should be considered in determining the appropriate well class for a carbon dioxide injection well that has been repurposed for long-term storage of CO_2 in an oil and gas reservoir, to the extent possible given information available to the Class VI UIC Program Director. Specific factors are discussed in detail in this section.

EPA recognizes that Class II wells may not necessarily transition to Class VI. This may be because an evaluation of the above factors results in a determination that a Class VI permit is not needed, either because the owner or operator determines that he/she does not want to proceed with or continue carbon dioxide injection and decides to plug the well, or because a determination is made that the Class II well was not sited or constructed in a manner that allows for safe, long-term storage of large volumes of carbon dioxide as a Class VI injector. In addition, a Class II well need not transition to Class VI even if its primary purpose changes to GS when there is no increased risk to USDWs. (See 40 CFR 144.19(a)).

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Pressure (e.g., hydraulic head) in the injection zone is a function of injection and production rates, distance from injection and extraction wells, time after initiation of injection and production, as well as the aquifer properties of the injection zone.

For the present example exercise, four injection/production scenarios are evaluated:

- Scenario 1: Oil production (primary purpose)* without carbon dioxide injection.
- Scenario 2: Oil production (primary purpose)* with low carbon dioxide injection.
- Scenario 3: Oil production with high carbon dioxide injection (either purpose)*.
- Scenario 4: Carbon dioxide injection (primary purpose)* without oil production.

  * As determined by owner/operator based on legal and economic factors.

Specific injection and extraction rates for each of these scenarios are presented in the following table:

	Injection Rate m3/d	Production Rate m3/d
Scenario 1	0	3000
Scenario 2	3000	3000
Scenario 3	4000	1000
Scenario 4	4000	0

The scenarios are designed such that the primary purpose of Scenario 1 is strictly oil production, as is that of ~~and Scenario 4 is strictly GS, while~~ Scenario 2, which represents a typical ER project. ~~and~~ Scenario 3 may represent either a declining-production ER project or an ER project~~s~~ that has declared its primary purpose is~~are~~ transitioning to GS.~~ and~~ For the latter purpose only, it~~therefore~~ must be evaluated for the necessity of a Class VI permit. Scenario 4 is a GS project in a depleted oil and gas field with a Class II permit that must be evaluated for the necessity of obtaining a Class VI permit. In the example, injection zone pressure increases from Scenario 1 to Scenario 4.

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Hypothetical values of pressure at the artificial penetration as a function of time for each of the four scenarios are presented in Figure 6. For Scenario 1, with production and no injection, injection zone pressure decreases, therefore decreasing risk of efflux of fluids out of the injection zone. For Scenario 2, injection and production rates are equal, and pressure in the injection zone remains nearly constant at levels only slightly above initial conditions. In Scenario 3, injection rates are greater than production rates, and injection zone pressure reaches the threshold level of 8.68 MPa at about 150 days. In Scenario 4, without any production, the threshold pressure is reached within 80 days after the start of injection. Therefore, for Scenarios 3 and 4, there is risk for efflux of native fluids into the overlying USDW, whereas for Scenarios 1 and 2 this is not the case. In these examples, Class II permits are appropriate under Scenarios 1 and 2, plus Scenario 3 when its primary purpose is ER, though its Class II permit may need some modifications to address the increased risk to USDWs. Class VI permits are appropriate under Scenarios 4 and 3, when their primary purposes are GS and the potential risks have

increased, unless the risks can be mitigated. If Scenario 4 shows no increased risk to USDWs, it could remain under its Class II permit or could change to Class VI if it makes economic sense.

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As discussed above, increased carbon dioxide injection rates may be used to increase the volume of carbon dioxide sequestered. Such an increase may indicate an increased risk to USDWs compared to Class II operations. However, a Class VI permit would be needed only if owner or operator changes the primary purpose from oil and gas production to long term storage and the increased risk can be demonstrated. Increased carbon dioxide injection rates are one of the key determinants of reservoir pressure and also result in an increased volume of carbon dioxide in the subsurface. Injection rates have the greatest influence on reservoir pressure in the region nearest the well bore, with decreasing influence further from the injection well.

Carbon dioxide injection rates are measured with a flow metering device (see the UIC Program Class VI Well Testing and Monitoring Guidance). For evaluation as a criterion, injection rates should be considered from an individual well or on a project basis by manifold monitoring. Monitoring of injection flow rates and pressures is required on at least a monthly basis for Class II ER wells [40 CFR 146.23]. Anticipated injection rates and pressures (average and daily maximum) are required information for authorization of a Class II permit [40 CFR 146.24]. Proposed injection rates and/or pressures are provided with the Class II permit application and are typically incorporated as operating conditions of the Class II permit. Any increase above those levels would be a violation of the Class II permit. When compared to historical data, injection rate increases for an extended time period may indicate increased risk to USDWs. Thresholds for the amount and duration of increase will be site-specific and based on historical operating records as well as the injection rate specified in the Class II permit. If the primary purpose has not changed, then enforcement action under Class II may be appropriate; if the primary purpose has changed, then ~~T~~taken in concert with other factors, injection rate increases may indicate the need for a Class VI permit.

Once a decision has been made to change the primary purpose of a well from ER to long-term storage, ~~O~~owners or operators may elect to decrease reservoir production rates in order to maximize carbon dioxide storage. ~~For example, produced fluids from EOR operations are typically a mixture of brine, hydrocarbons and carbon dioxide. As the efficiency of the EOR operation decreases over time, the amount of hydrocarbons in the produced fluids decreases.~~ Production well pressure control has been described as a possible way to increase carbon dioxide storage at EOR facilities. This involves reduction of production rates when carbon dioxide levels in the produced fluid become high (Kovscek and Cakici, 2005). If a reduction in production rate results in an increased potential risk to USDWs, then the well may need to be repermitted under Class VI. If, however, the production decrease does not increase the potential risks to USDWs, then the well may remain permitted under Class II.

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For a project transitioning from ER to GS, the original Class II AoR delineation may no longer be adequate. For example, elevated pressure and/or fluid migration may occur outside of the Class II delineated AoR. This is demonstrated by the hypothetical example provided in Box 1 (on pages 21 to 23) and Box 2 (on page 26). The artificial penetration in this hypothetical example is located 1/4 mile (approximately 400 meters) from the injection well and could, therefore, be at the outermost boundary of a Class II AoR delineation. As shown in Figure 7, as operational parameters at the project change to more closely represent GS rather than ER, reservoir pressure at artificial penetrations in the AoR may increase to levels that may cause fluid movement into a USDW. In these cases, the AoR should be re-

delineated under Class II authorities to include any area that exhibits this elevated pressure. If a project's primary purpose changes from ER to GS and presents an increased risk to USDWs~~Under these circumstances~~, a Class VI permit may be required for continued injection well operation.

Any monitoring data that indicate the presence of carbon dioxide or the pressure front (elevated pressure great enough to cause fluid movement into the lowermost USDW) demonstrated to be directly attributed to the injection well in question beyond the Class II AoR for that well is evidence that the AoR does not meet the Class VI requirements. Furthermore, relatively simple analytical modeling or more sophisticated computational modeling may be needed to estimate whether the Class II AoR delineation is adequate in comparison to AoR requirements under the Class VI Rule. EOR operations routinely use sophisticated computational modeling and uncertainty analysis to plan and evaluate the project, and this modeling may be used to assess the adequacy of the current AoR delineation.

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In approving a Class II permit application, the Class II UIC Program Director is required to consider the status of corrective action on wells within the AoR [40 CFR 146.24], including: (1) the type and number of plugs to be used; (2) the placement of each plug including the elevation of the top and bottom; (3) the type, grade and quantity of cement to be used; and (4) the method of emplacement of the plugs. This information should, therefore, be available to the Class VI UIC Program Director and may be provided in abandoned well plugging records and/or plug field testing. If the owner or operator ~~or the Class VI UIC Program Director~~ determine from consideration of other factors that the project may be transitioning to GS and a Class VI permit is required, the quality of abandoned well plugs should be considered.

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Because the objective of GS is to maximize carbon dioxide storage, owners or operators will typically leave the injected carbon dioxide in place after injection. Therefore, fluid pressures in the injection zone will likely remain elevated above pre-injection levels for some period of time, and a large volume of carbon dioxide will remain in the subsurface. ~~Separate phase carbon dioxide left in place poses a risk to USDWs because if the storage project has not been appropriately sited and operated, carbon dioxide may leak upward through leakage pathways (such as improperly abandoned wells or transmissive faults or fractures) due to buoyancy, or cause upward or downward movement of formation fluids due to elevated pressure.~~ For example, modeling calculations indicate that accumulation of supercritical carbon dioxide at a thickness of…..

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Following a change of primary purpose and a determination that there is an increased risk to USDWs from the injection project (see Section 3), owners or operators will need to apply for a Class VI permit. This section describes additional Class VI requirements that owners or operators must meet following a determination that a Class II ER project will transition to a Class VI GS project. Section 4.1 briefly describes well construction requirements for Class II ER wells. Section 4.2 presents Class VI well construction requirements and identifies considerations that may be appropriate for the conversion of Class II wells to Class VI wells. Section 4.3 describes the operating-phase requirements that owners or operators must meet under a Class VI permit. Finally, Section 4.4 discusses how owners or operators following the individual well permitting requirements for Class VI wells can achieve some of the efficiencies of area permits that are allowed under some other UIC well classes.